

SECTION 3.5

NATURAL GAS ASSESSMENT

INTRODUCTION

New York State currently uses approximately 1,200 million dekatherms (MMDT) of natural gas per year, making it the fourth largest gas consuming state in the nation behind Texas, California, and Louisiana.¹ The State has approximately 4.6 million natural gas customers² served by eleven local gas distribution companies (LDCs).³ These LDCs depend on major interstate and intrastate pipeline systems for access to domestic and Canadian gas supplies.⁴ Domestic gas, primarily from the Gulf Coast area, accounts for approximately 62% of the gas consumed in New York with nearly all of the remainder from Canadian sources.⁵ Gas production within New York is growing and currently meets about 2% of the State's annual gas use.

Competitive forces have changed the gas industry dramatically and will likely continue to do so. As explained below, federal and State policies to enhance competition have been adopted and are being expanded.

Natural gas demand is expected to increase significantly, especially to generate electricity. Plans to build about 15,000 MW of new gas fired generation have been announced in New York. These plants combined would require about 2,500 thousand

¹ The New York State breakdown of the volumes by sector: residential 35%; commercial/ industrial 30%; power generation 35%.

² The New York State breakdown by sector is: 4.2 million residential customers (including 1.7 million customers who use gas only for cooking or water heating) and 0.4 million commercial/industrial/power generation customers.

³ Central Hudson Gas & Electric Corporation (CHG&E), Consolidated Edison Company of New York, Inc. and Orange & Rockland Utilities (Con Edison/O&R), Corning Natural Gas Company (Corning), KeySpan Energy Delivery of New York and KeySpan Energy Delivery of Long Island (KeySpan), Niagara Mohawk Power Corporation (Niagara Mohawk), New York State Electric and Gas Corporation (NYSE&G), Rochester Gas & Electric (RG&E), National Fuel Gas Distribution Company (NFGD), and St. Lawrence Gas Company (St. Lawrence).

⁴ These pipelines are: Algonquin Gas Transmission Co. (AGT), Columbia Gas Transmission Corp.(Columbia), Dominion Transmission, Inc. (DTI), Empire State Pipeline Co. (Empire), Iroquois Gas Transmission System (IGTS), National Fuel Gas Supply Corp. (NFGS), North Country Pipeline, Tennessee Gas Pipeline Co. (Tennessee), Texas Eastern Pipeline Co. (TETCO), Transcontinental Gas Pipe Line Corp. (TRANSCO), and TransCanada Pipelines, Ltd. (TransCanada).

⁵ Natural Gas Annual 1999, EIA, issued October 2000.

dekatherms of gas per day (MDT/D) if operated at full capacity.⁶ Not all of these plants will be built (some have been canceled or delayed) and, as explained later, the ongoing study, “The Interaction of the Gas and Electric Systems in New York State” (NYSERDA-NYISO study) indicates that far less incremental natural gas pipeline capacity actually will be needed. In addition, the use of gas in core markets continues to grow, especially in the downstate (New York City-Long Island) area. Additional pipeline capacity, as well as expansion of distribution system capacity will be needed to meet the anticipated increase in gas use. A number of projects have been proposed to expand pipeline capacity to New York State.

As explained below, gas prices increased to unprecedented levels during the 2000-2001 winter due to a combination of factors and have since returned to more historic levels. However, gas prices will likely remain volatile.

Finally, the security of gas delivery facilities has not been a problem historically. However, in light of the September 11, 2001 terrorist attacks, Governor Pataki has created the Office of Public Security to assess the vulnerability of critical infrastructures to terrorist attacks and to develop a comprehensive, Statewide anti-terrorism strategy. Concurrently, the Department of Public Service has established the Security Assessment Team to assess utility efforts to maintain system reliability and security.

NATURAL GAS COMPETITION

Status of the New York State Retail Market

Large-volume natural gas customers in New York have been able to choose from non-utility suppliers since the mid-1980s. In 1996, the Public Service Commission (PSC) extended the opportunity to purchase gas from non-utility suppliers to all customers. As of December 2001, approximately 373,000 residential and smaller non-residential customers had switched to non-utility suppliers. These customers use approximately 102 MMDT of natural gas per year, or about 10.4% of the total volumes delivered to customers by the LDCs. Most large volume customers switched to a non-utility gas supplier years ago. In total, about 50% of the gas consumed in New York is gas purchased from non-utility suppliers. There are about 25 active marketers in the

⁶ Current pipeline delivery capacity to New York is roughly 6,000 MDT/D, and this capacity is needed to meet existing core market (residential, commercial, and industrial) demand on a peak winter day.

downstate area, and about 15 in upstate New York. The retail gas market in New York is approximately a \$7.5 billion per year market.⁷

Status of the Wholesale Natural Gas Market

Natural gas commodity prices have been completely deregulated for over ten years. The New York Mercantile Exchange (NYMEX) futures price is the benchmark price for natural gas nationwide, with futures contracts quoted at, and deliverable to, the Henry Hub, in Katy, Louisiana. Several market area hubs or liquid trading points⁸ have emerged, including Dawn, Ontario, the Columbia pool, and DTI Southpoint. The establishment of additional market area hubs/liquid trading points is critical to the development of a competitive wholesale natural gas market closer to market demand.

Policies to Enhance Competition

New York State. In 1998 the PSC issued a Policy Statement establishing its vision for the future of the natural gas industry in New York.⁹ The essence of that vision is that the most effective way to establish a competitive retail market in gas supply is for LDCs to cease selling gas.¹⁰ The Policy Statement requires LDCs to hold new upstream pipeline capacity contracts to the absolute minimum necessary for system operation and reliability purposes and eliminates the LDCs' right to assign its capacity to migrating customers, except where specific operational and reliability requirements warrant. This encourages LDCs to relinquish capacity as contracts expire to make it available for marketers. A transition process consisting of three elements was established:

Discussions with each LDC on an individualized rate and restructuring plan;

- Collaboration among stakeholders on the key generic issues of system reliability and market power; and

⁷ Customer costs for LDC sales and transportation services are about \$5 billion per year and payments to non-utility suppliers are roughly \$2.5 billion per year.

⁸ Generally defined as points where gas is readily available.

⁹ Case 93-G-0932, Proceeding on Motion of the Commission to Address Issues Associated with the Restructuring of the Emerging Competitive Natural Gas Market; Case 97-G-1380 In the Matter of Issues Associated with the Future of the Natural Gas Industry Need and the Role of Local Gas Distribution Companies, Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment, (issued November 3, 1998).

¹⁰ In this vision marketers would sell gas to customers and LDCs would deliver that gas to them.

Coordination of issues that are also faced by electric utilities, including provider-of-last-resort and competition in areas such as metering, billing, and information services.

Multi-year rate and restructuring plans have been approved for all major LDCs. Generally, these plans freeze or reduce retail rates, establish back-out rates applicable when marketers replace certain LDC functions, establish or refine balancing services for marketers, incorporate gas capacity portfolio changes, and promote development of the competitive market through customer information programs.

A Reliability Collaborative was established in December 1998 to implement the Policy Statement's goal of maintaining the reliability of gas deliveries. Based on recommendations developed through this collaborative, the PSC requires marketers serving firm loads to have firm, primary delivery point capacity for the months of November through March, with a limited exception for KeySpan.¹¹ LDCs were also required to develop Gas Transportation Operations Manuals to codify all procedures that marketers must follow. A Natural Gas Reliability Advisory Group was established in the fall of 2001 to provide a forum for a continuing dialog on reliability issues and to advise staff and the PSC on reliability and related issues. Members of the Advisory Group include staff as well as representatives of various stakeholder groups: LDCs, pipeline companies serving the State, wholesale marketers, retail marketers, electric generators and customers. The Advisory Group meets monthly to discuss a range of topics that impact gas capacity markets and gas reliability.

Upstate LDCs (NFG, NYSE&G, Niagara Mohawk, and RG&E) have been able to relinquish capacity on upstream pipelines as contracts expire, resulting in net capacity cost savings of about \$55 million per year to New York gas customers. Downstate LDCs (KeySpan and Con Edison /O&R) relinquished a small amount of capacity to their city-gates when the contracts expired on November 1, 2000, in anticipation of retail marketers acquiring this capacity. However, a wholesale marketer affiliated with an electric generation company acquired that capacity. Wholesale marketers with power generation interests recently acquired available capacity in the broader downstate market for periods of up to ten years.

The downstate capacity market has become tight, and marketers that acquire capacity at market prices cannot compete with the LDCs' weighted-average cost of capacity. In response, the downstate LDCs have developed programs under which they

¹¹ Due to the structure of its supply and capacity portfolio KeySpan was able to allow marketers to use non-primary capacity to meet a portion of their requirements.

will acquire the resources needed to meet market requirements on a year-to-year basis and make capacity available to marketers at their average cost of capacity for three years.¹²

Finally, the 2000-2001 winter led to the bankruptcy of one retail marketer and the withdrawal of another retail marketer from the residential market in Western New York. These failures were caused by cash flow problems associated with high gas costs and the lack of marketer action to manage price risk. Most of the customers served by these marketers were returned to the LDC who was able to acquire the capacity needed to serve them. The widely publicized bankruptcy of Enron in December 2001 did not have a significant impact on New York for two reasons. First, Enron's retail and wholesale gas marketing units provided gas to a relatively small number of customers in New York and a relatively small amount of gas New York LDCs, respectively. Second, the weather in the winter of 2001-02 was extremely mild and gas storage inventories were very high. As a result, finding replacement gas supplies was not a problem.

Several issues common to gas and electric that impact the development of the competitive market are being addressed in a coordinated fashion. These issues include provider-of-last-resort, billing and metering, electronic data interface, uniform business practices, and unbundling of costs. The Electricity Assessment contains a detailed discussion of these issues.

Federal. In the mid-1990s the Federal Energy Regulatory Commission (FERC) eliminated the merchant role of interstate pipeline companies and transferred responsibility for gas supply acquisitions to LDCs and customers. FERC issued Orders 637 and 637-A in 2000, waiving price ceilings for short-term released capacity for a two-year period, permitting use of peak/off-peak and term differentiated rate structures, allowing capacity segmentation, revising scheduling procedures, narrowing the right of first refusal and improving reporting requirements and penalty provisions. These changes are intended to improve the efficiency of the interstate pipeline capacity market.

Pipeline companies were required to file Order 637 tariffs beginning in the fall of 2000 on a staggered basis. Tariff changes to comply with FERC Order 637 have been approved by FERC for AGT, DTI, IGTS, NFGS and TETCO. Proposed tariff changes are pending FERC approval for Columbia, Tennessee, Texas Gas, and Transco.

¹² Case 97-G-1380, In the Matter of Issues Associated with the Future of the Natural Gas Industry Need and the Role of Local Gas Distribution Companies, (untitled Order dated July 27, 2001).

One of the common issues among the pipelines is the cash-out mechanism for customer imbalances. With new services and new information systems now available, there is less reason for customers to remain out of balance between their daily nominations and daily takes. Weekly, rather than monthly, cash-out of imbalances have been proposed by two pipelines.

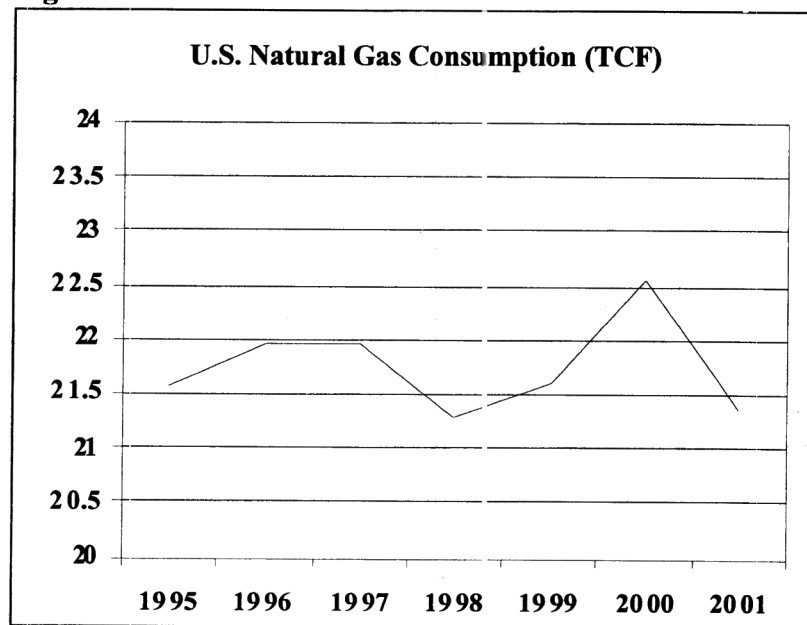
The changing nature of the natural gas market has resulted in the development of new pipeline service offerings. One such development is the opportunity for shippers to make intra-day nominations, providing more flexible use of pipeline capacity to meet changes in system demand. Another is the introduction of increased hourly delivery quantity flexibility, a service specifically designed for electric generators. Another example, which is being used in the retail access programs in New York, is the development by DTI of its Delivery Point Operator/Customer Swing Service. This essentially allows marketers access to no-notice services with the LDC acting as the delivery point operator thereby administering a program to account for each marketer's use of such services to meet daily swings.

NATURAL GAS MARKET DEVELOPMENTS

Natural Gas Demand. Lower oil prices resulted in a decline in United States (U.S.) gas demand in 1998. However, gas demand recovered somewhat in 1999 and increased another 5% in 2000, the result of a strong national economy and the increased use of gas for power generation (see Figure 1). Gas demand declined by 5 % in 2001 due to the

slowing of the economy, which was accelerated by the September 11, 2001 terrorist attacks, higher prices, and the mild winter weather. U.S. gas demand is expected to

Figure 1



increase significantly to 32.7 trillion cubic feet (TCF)¹³, a 40% increase, by 2016.¹⁴

In New York, demand for gas in core markets (residential, commercial, and industrial) continues to grow, especially in the downstate area where the saturation of gas use is relatively low and there is a large potential conversion market. The most significant increase in gas use will be for power generation. Of this amount, about 70% is proposed in the area from Rockland and Orange counties through Long Island. In addition, the Governor's Clean Air Act Initiative, discussed in the Environment and Energy report in this Plan, will likely result in increased use of gas for power generation. Finally, the use of gas may increase in two other markets: the distributed generation market and the use of compressed natural gas as a transportation fuel. The increased use of gas in these markets could require improvements to gas distribution systems.

Natural Gas Commodity Prices

Natural gas commodity prices soared to unprecedented levels during the 2000-2001 winter. Several factors contributed to this increase. A sustained period of relatively low gas prices in the 1990s led to a substantial reduction in gas drilling, constraining domestic productive capacity. This set the stage for the price increase, but two factors that suppressed gas demand concealed the significance of the problem. First, low oil prices in 1998 and 1999 reduced gas demand through fuel switching to oil. Second, prior to last winter, there were three warm winters in a row, masking the underlying level of gas demand. U.S. natural gas consumption declined by 3% in 1998, grew by 2% in 1999, and grew by another 5% in 2000, as a result of a strong national economy, rising oil prices, and increased use of gas to generate electricity. In the spring of 2000, prices were still at a level of about \$2.50-\$3.00/DT. However, the summer of 2000 was unusually warm in the Southwest where substantial air conditioning load is met through gas-fired generation. Gas prices started rising steadily in response to the increased summer gas demand and the competing need to fill gas storage. By the beginning of the 2000-2001 heating season, prices were already at record high levels and storage inventories were still relatively low. The sustained cold weather in November and December 2000 (the 2nd and 7th coldest ever recorded, respectively), in combination with market nervousness due to low gas storage levels, caused gas prices to increase dramatically to nearly \$10/DT. The balance of the 2000-2001 winter was mild, drilling for gas increased in response to higher gas prices, the national economy slowed, and storage had been refilled at record levels. As a result, gas prices have returned to more

¹³ A TCF is roughly equal to 1,000 MMDT.

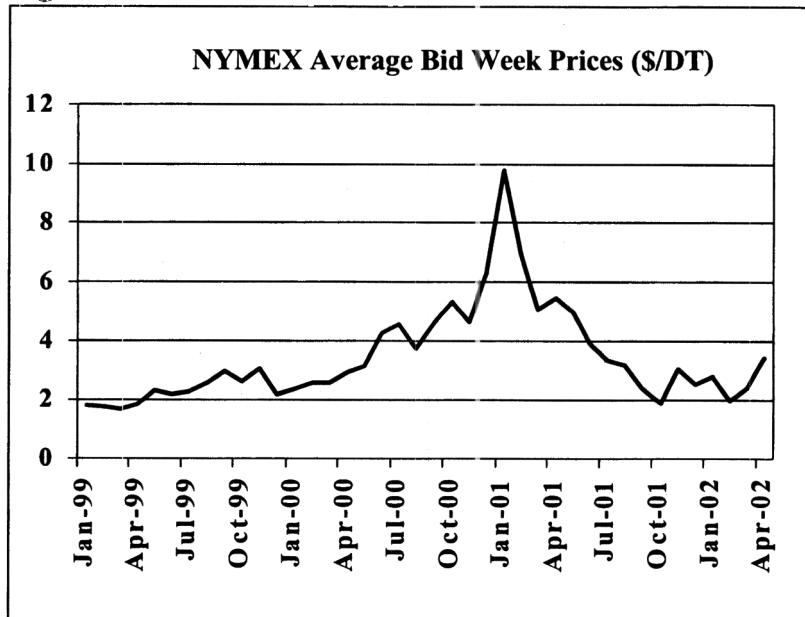
¹⁴ Annual Energy Outlook 2002, Energy Information Administration, December 2001.

familiar levels (see Figure 2). However, gas prices will likely remain volatile.

In 1998, the PSC issued a Policy Statement on LDC gas purchasing practices.¹⁵ The Policy Statement allowed the prudent use of financial instruments, such as “hedging” as a tool to mitigate price volatility. While the

PSC did not direct any particular mix of portfolio options, it stated that volatility of customer bills is one criterion, along with other factors such as cost and reliability, that LDCs should consider in their gas supply portfolio strategies. The PSC stated that excessive reliance on any one gas pricing mechanism or strategy does not appear to reflect the best management of the gas portfolio and any LDC without a diversified gas pricing strategy will have to meet a heavy burden to demonstrate that its approach is reasonable.

Figure 2



Natural Gas Supplies

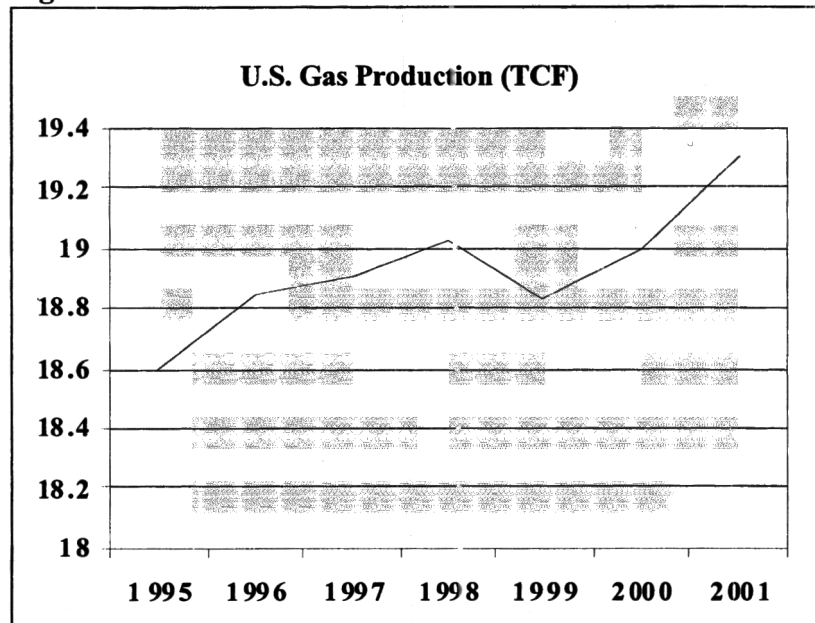
Domestic Gas. U.S. gas production in 2001 was 19.3 trillion cubic feet (TCF), a 1.7% increase over 2000 (see Figure 3).

Weakening gas prices in the late 1990s led to a reduction in gas drilling activity from 657 rigs in December 1997 to 362 rigs in April 1999. Gas rig activity began to reverse its downward trend during 1999, reaching 854 rigs by December 2000, and peaked at 1,058 rigs in July 2001 (see Figure 4). Gas rig activity has since declined to 617 in March 2002. Changes in gas rig activity are correlated with the changes in gas prices.

¹⁵ Case 97-G-0600, In the Matter of the Commission's Request for Gas Distribution Companies to Reduce Gas Cost Volatility and Provide for Alternative Gas Purchasing Mechanisms, Statement of Policy Regarding Gas Purchasing Practices, (issued April 28, 1998).

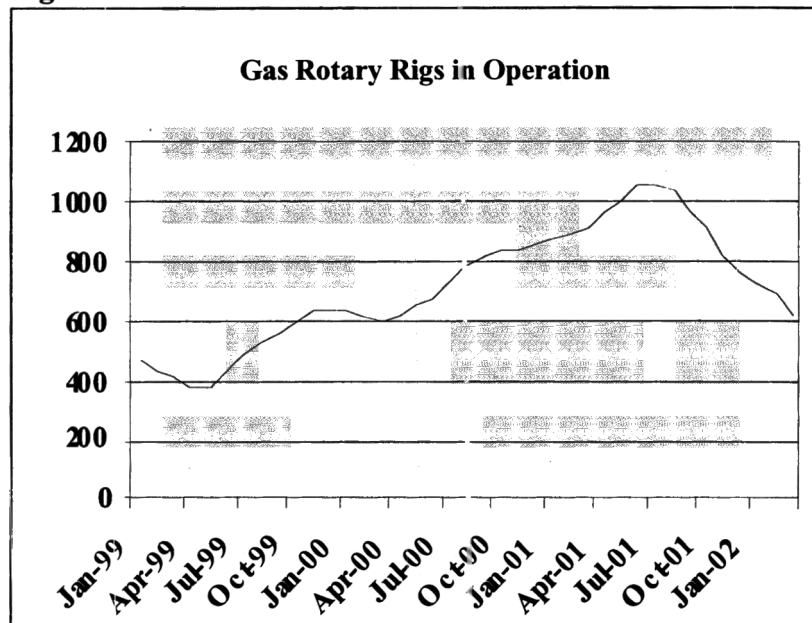
Proven natural gas reserves¹⁶ for the lower 48 states totaled 168 TCF at the end of 2000. The amount of proven reserves has held fairly steady at about this level for the last ten years as cumulative production of 187 TCF over the last decade was offset by reserve additions. Potential gas reserves¹⁷ are currently estimated at 1,206 TCF for the lower 48 states.

Figure 3



In addition, Alaska has 10 TCF of proven reserves and 34 TCF of potential reserves from conventional sources. Further, Alaska has about 210 TCF of reserves from unconventional sources, such as oil shale and coal-bed seams.

Figure 4



Two pipeline route alternatives are

¹⁶ Proven natural gas reserves are those which analysis of geologic and engineering data demonstrates with reasonable certainty to be recoverable from known reservoirs, under existing economic and operating conditions.

¹⁷ Potential resources include all the undiscovered gas resources plus that part of the discovered resource that is not included in proven reserves.

being considered to bring Alaskan gas to the lower 48 states. The “southern” route would parallel the Trans-Alaska oil pipeline and then follow a route parallel to the Alaskan Highway through the Yukon Territory and British Columbia, to connect with existing pipelines in Alberta. This alternative would be about 2,000 miles long and cost about \$10 billion. The “northern” route would extend east from the Alaskan North Slope to Canada’s Mackenzie River delta where it would access additional gas supplies, and then south along the Mackenzie valley into Alberta. This alternative would be about 1,650 miles in length and cost about \$8 billion.

Canadian Gas. Imports of Canadian gas historically have been from Canada’s Western Sedimentary Basin (primarily Alberta). On December 31, 1999, Canadian gas imports began from offshore Nova Scotia (Scotian Shelf area) through the Maritimes & Northeast Pipeline (M&NE). Canadian imports into the U.S. totaled 3.7 TCF during 2001, an increase of about 6% over 2000.

Imports of Canadian gas have increased steadily since 1995. The U.S. imported roughly 17% of its total requirements from Canada during 2001. About 23% of the gas volumes coming into the mid-Atlantic region (NY, NJ, and PA) originate in Canada;¹⁸ however, some of this gas continues on to New England.

Western Canadian Sedimentary Basin proven reserves totaled 63.9 TCF as of January 1, 2000. The Scotian Shelf area contains 3 TCF of established reserves (proven reserves that are connected to pipelines), 2 TCF of discovered resources (proven by drilling but not yet connected to pipelines), and 13 TCF of undiscovered potential reserves.¹⁹

LNG. Liquefied natural gas (LNG) imports have risen dramatically over the last several years (see Figure 5). After nearly doubling in 1999, LNG imports continued their growth in 2000 to a total of 223 MMDT, a 35% increase over 1999. Trinidad and Tobago and Qatar surpassed Algeria for the first time as suppliers of LNG to the U.S. in 2000.²⁰

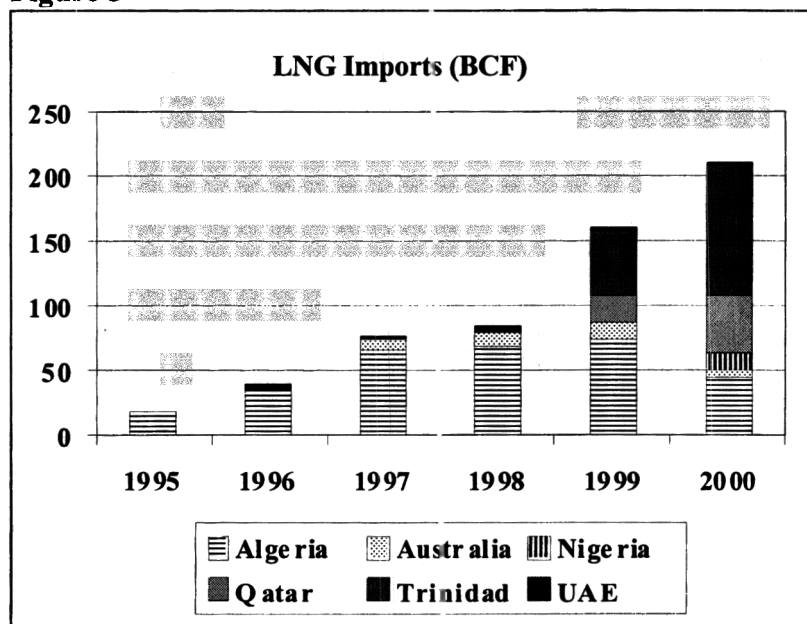
¹⁸ Source: Natural Gas Annual 2000, EIA (issued November 2001).

¹⁹ Canadian Natural Gas: Review of 1999 & Outlook to 2010, May 2000

²⁰ Trinidad supplied 96 BCF of LNG, or 44% of total LNG imports in 2000 and Qatar supplied 46 BCF of LNG or 21 percent. Algeria continued to be a major supplier of LNG accounting for 44 BCF or 20% of all LNG imports.

There are two operational LNG receiving terminals in the U.S. located at Everett, MA, and Lake Charles, LA. Imports into Everett totaled 99 MMDT in 2000, an increase of 3% over 1999.²¹ Following the terrorist attacks of September 11, 2001, the U.S. Coast Guard banned LNG deliveries to Everett, MA, but has since lifted the ban.

Figure 5



Expansion of LNG imports is expected in the future. TRANSCO received FERC approval to reactivate import capability at its Cove Point, MD, LNG facility by 2002, which has not received any imports since 1980. The Elba Island terminal near Savannah, GA has received FERC approval to resume LNG imports and is expected to begin receiving shipments in 2002. In addition, about a dozen other LNG projects have been announced. Several are proposed in Texas, and would use either existing pipelines or build new ones to deliver re-gasified LNG for electricity generation customers. On the East Coast, expansion of the Everett, MA facility is planned to fuel a new 1,550 MW power plant currently being built nearby. A new plant is planned for Radio Island, NC to serve markets that are too distant from large pipelines.

In New York, LNG plays a critical role in meeting peak winter requirements. Instead of imports, this use of LNG involves liquefying pipeline gas during the summer, storing that LNG in insulated tanks, and re-gasifying it to meet peak day requirements.²²

²¹ Almost 81% of the imports received in Everett came from Trinidad, primarily under long-term arrangements. The Lake Charles facility received 124 BCF, an increase of almost 85% over 1999.

²² The 1998 *Report on Issues Regarding the Existing New York Liquefied Natural Gas Moratorium*, by the State Energy Planning Board, led to legislation that lifted the then-existing moratorium on siting new LNG facilities, except in New York City.

New York State Resources

The first natural gas well in the U.S. was drilled in Fredonia, NY in 1821. Historically, most wells in New York were drilled to sandstone formations at depths of 1,000 to 4,500 feet, and produced relatively small amounts of gas (up to 100 DT/D) for many years. Today there are approximately 6,600 gas wells in New York that produce a total of about 18.5 MMDT.

Over the last three years, exploration and development of the Trenton and Black River Group has intensified. This is a prolific and deep play (7,000 to 11,000 feet), with some wells producing as much as 10,000 DT/D. It has been under development in Canada and other states for some time. During 2000, natural gas was produced from the Trenton and Black River in Steuben and Chemung Counties. Production from 23 such wells totaled 5.3 MMDT, or about 30% of total Statewide natural gas production of about 18.5 MMDT (from less than 1% of the total number of wells). The New York State Department of Environmental Conservation staff expects that between five and ten additional wells will be placed into production during 2001, and that production from just the Trenton and Black River Group may reach 12 MMDT or more. Drilling is most active in the southern Finger Lakes area of Steuben, Schuyler, and Chemung Counties, but wells have been drilled as far west as Cattaraugus County and as far east as Cortland County.²³

In an effort to expand natural gas production in New York, the New York State Energy Research Development Authority (NYSERDA) is working with exploration companies to improve the identification of carbonate reservoirs and increase the geographic distribution of production. Along with the Trenton and Black River groups, other carbonates under investigation include the Beekmantown Group and the Onondaga Formation. NYSERDA is also researching improved detection mechanisms to reduce the dry hole ratio. Some NYSERDA projects are located in areas that currently have little or no production, such as the Tug Hill Plateau and Otsego County.

²³ From 1995 to 2000, 75 wells were drilled to explore for and develop Black River gas reserves. Drilling on 22 of these wells were begun in 2000. By August 1, 2001, 35 applications had been received for Black River wells, a 46% increase over the number of applications received by the same time in 2000.

MERGERS AND ACQUISITIONS

New York LDCs

Mergers and acquisitions continue to reshape the way in which LDC services are provided. KeySpan Corporation acquired three Massachusetts gas utilities (Boston Gas, Colonial Gas, and Essex County Gas); Con Edison acquired Orange and Rockland Utilities; and Energy East (the parent of NYSEG) acquired Berkshire Gas, a Massachusetts gas utility, Connecticut Natural Gas Corporation and Southern Connecticut Gas Company, and established the Maine Natural Gas Company. A merger between Niagara Mohawk and National Grid Corporation has been completed. Energy East's acquisition of RGS Energy Group, Inc., the parent of RG&E, is pending.

Interstate Pipelines

Four major mergers have been completed involving interstate pipeline companies that serve New York. Dominion Resources (an electric utility based in Virginia) acquired CNG Transmission Corporation and it became Dominion Transmission, Inc. (DTI). Columbia Gas Transmission was acquired by NiSource a Merrillville, IN based holding company. El Paso Corp., owner of Tennessee, acquired the Coastal Corporation. El Paso now owns and operates the largest pipeline system in the country, extending from California to Texas, and from Texas to Massachusetts and Illinois. Finally, Duke Energy recently acquired Westcoast Energy. Duke is a diversified energy company headquartered in Charlotte, NC, and is parent of TETCO and AGT as well as part owner of the Maritimes & Northeast Pipeline (M&NE). Westcoast is a leading Canadian natural gas company based in Vancouver, BC and is parent of Union Gas, Empire State Pipeline, the Westcoast Pipeline (which serves CA), as well as part owner of M&NE.

Analysis of Natural Gas Market Developments

Competition for available capacity is developing between the core market and the electricity generation market. The use of gas to generate electricity has increased, because of the increased demand for electricity. Further, there is an expectation that the use of gas for electricity generation will increase significantly as a result of proposed new gas-fired generation facilities.

Retail marketers to date have not acquired the capacity necessary to serve their customers except on a short-term basis. Many factors have contributed to this situation such as the tightness in the capacity market, commodity cost volatility, and access to

competitively priced capacity. It is not clear whether retail marketers will ever be willing to make capacity commitments or whether the role of holding capacity will be filled by wholesale marketers. Meanwhile, wholesale marketers have begun to acquire capacity, ostensibly to serve the power generation market. Thus, electric market developments are increasing competition for available pipeline capacity and changing the dynamics of the gas capacity market.

INFRASTRUCTURE ISSUES

Current Interstate Pipeline Delivery Capacity

Interest in expanding interstate pipeline delivery capacity to New York and the Northeast continues to be strong. Three major projects have recently been completed to increase delivery of Canadian gas to the Chicago market area. The new Alliance Pipeline,²⁴ which extends 1,860 miles from Alberta, Canada to the Chicago, IL area, began service on December 1, 2000, and has a capacity of 1,325 MDT/D. The new Vector Pipeline,²⁵ which extends from Chicago to Dawn, Ontario, also began service on December 1, 2000, with an initial capacity of 700 MDT/D. The existing Northern Border Pipeline was extended from Harper, IA to Manhattan, IL and its delivery capacity increased by 700 MDT/D beginning in December 1998. In the East, the Maritimes & Northeast Pipeline (M&NE), which extends from Sable Island, through Nova Scotia and New Brunswick, Maine and New Hampshire to the Boston, MA area, began service at the end of 1999. It has delivery capacity of 440 MDT/D, and "back feeds" the existing gas delivery systems serving the Northeast with a new competitively priced and sizable gas supply. Several of the projects proposed to serve the Northeast would expand access to these Canadian gas supplies.

Approved Projects

FERC has approved the following projects to increase capacity to New York and the Northeast:

MarketLink Phase I & II. The MarketLink projects will expand capacity of the existing TRANSCO Leidy line, which extends from storage facilities in Leidy, PA to the New York City market, in two phases. Phase I increased capacity by 115 MMCFD to

²⁴ The sponsors of Alliance are Fort Chicago Energy Partners 26%, Westcoast 23.6%, Enbridge 21.4%, Williams 14.6%, and Coastal 14.4%.

²⁵ The sponsors of Vector are Enbridge, Westcoast, and the MCN Energy Group.

New York City in December 2001. Phase II will increase capacity by 130 MMCFD to New Jersey and Pennsylvania by November 1, 2002. These expansions will be accomplished through pipeline looping²⁶ and added compression within the existing pipeline right-of-way. MarketLink was proposed as the final link to bring Western Canadian and Midwestern gas supplies to the East Coast. The Independence Pipeline in combination with an upgrade of the ANR Pipeline (described below) would link MarketLink with the Chicago market area.

Independence Pipeline. The Independence Pipeline is a proposed 36-inch diameter pipeline that would extend 370 miles from Defiance, OH to TRANSCO's facilities at Leidy, PA, and have a capacity of 916 MDT/D.²⁷ Independence has a proposed in-service date of summer 2003. ANR Pipeline's SupplyLink Project will expand its existing ANR pipeline between Sandwich, IL and Defiance, OH by 750 MDT/D through a combination of added compression and looping to feed the Independence Project with a targeted in-service date of summer 2003. FERC has approved both of these projects, subject to certain conditions.

Stagecoach. This project involves development of new 12 MMDT storage facility in Tioga, NY and Bradford, PA.²⁸ In addition, Tennessee constructed a new a 23.7 mile, 30 inch diameter pipeline connecting this storage field to its "300 line" in PA and a new 4.7 mile, 12-inch diameter lateral would be built from this storage facility to the proposed Twin-Tier power plant in Owego, NY. The storage facility has withdrawal rates of up to 500 MDT/D and injection rates of up to 250 MDT/D. Tennessee also expanded capacity on that line to NJ by 100 MDT/D. One company²⁹ has contracted for 400 MDT/D of capacity on the lateral (out of 500 MDT/D) and 90 MDT/D (out of 100 MDT/D) on Tennessee's "300 line" for 10 years. All of these facilities went into service in December 2001.

Hanover Compressor. AGT and TETCO filed a joint application to increase the ability of TETCO to deliver gas to New York City by 135 MDT/D. This was accomplished by adding compression to AGT's existing compressor station in Hanover, NJ, allowing TETCO to shift some of its existing deliveries to AGT from the

²⁶ The addition of pipeline segments parallel to an existing pipeline to increase its capacity.

²⁷ The sponsors of Independence are ANR Pipeline Co., TRANSCO and National Fuel Gas Supply Corp.

²⁸ The sponsor of this storage project and the pipeline lateral is Central NY Oil & Gas Company.

²⁹ ECORP a marketing affiliate of Central NY Oil & Gas.

Lambertville, NJ interconnect. FERC approved this project on July 26, 2001, and the facilities were in-service in November 2001.

Leidy East. The Leidy East project involves looping and added compression in PA and NJ to expand the capacity of TRANSCO's Leidy line by 130 MMCFD.³⁰ Construction is scheduled to begin in April 2002 and the proposed in-service date is November 2002.

Dracut Expansion. Tennessee's Dracut Expansion Project will increase its ability to move gas from Dracut, MA to the west by 200 MDT/D. The project involves replacing 12 miles of 16-inch diameter pipe with 24-inch diameter pipeline. This project was filed at FERC in May 2001, and has an expected in-service date of fall 2002.

Iroquois' Eastchester Expansion. Involves construction of 33 miles of 24-inch pipe from the existing Iroquois mainline at Northport, LI to the Bronx, NY where it will interconnect with the Con Edison system. This project will increase capacity by 230 MDT/D, primarily for electric generation customers, with an expected in-service date of Spring 2003. Iroquois received FERC's approval for this project in December 2001. As part of this project, Iroquois will have to build new compressor stations in Boonville and Dover, NY and modify the existing Croghan, Wright, and Athens, NY compression stations to support the proposed deliveries through Eastchester.

Maritimes & Northeast Extension and Hubline. The Maritimes & Northeast Extension will be a new 25-mile pipeline extending Maritimes from Methuen to Beverly, MA. This line will interconnect with the Hubline pipeline, a new 29-mile, 24-inch diameter pipeline that would extend from Beverly, MA across Boston Harbor to an onshore interconnection with AGT's existing facilities in Weymouth, MA. Hubline would have a capacity of 300 MDT/D. Both of these projects have been approved by FERC and have a proposed in-service date of November 2002.

Cove Point Maryland LNG. TRANSCO plans to reactivate the import capability of its Cove Point, MD, LNG facility and expand its storage tank capacity by 50%. Cove Point was originally built with an import terminal, which was last used in 1980 and has since been dismantled. FERC has approved the project and construction is scheduled to begin in the 2nd quarter of 2002. The receipt of LNG shipments is expected in the 4th quarter of 2002, with the additional tank capacity scheduled for completion in the 4th quarter of 2004.

³⁰ This project is a replacement for the previously proposed phase III of MarketLink which was rejected by FERC because TRANSCO failed to secure precedent agreements with customers for the total volumes proposed for this phase of the project.

Proposed Projects

Several pipeline projects had been proposed for completion in the 2000-2002 time frame, but delays in the review and approval process have pushed the startup dates back. Since some of these projects compete with each other, it is likely that not all of these pipelines will be built.

The Millennium Pipeline.³¹ Millennium would be a 36-inch pipeline that would extend 424 miles from a new interconnection with TransCanada Pipelines in Lake Erie to a termination point in Mt. Vernon, NY where it would interconnect with Con Edison facilities. Most of the route would follow the existing Columbia right-of-way. Millennium would provide access to Canadian gas and the Chicago market area through Union Gas as well as access to storage in Michigan and Ontario. The capacity of Millennium would be 700 MDT/D, of which 350 MDT/D would be for the New York City area. FERC has approved the route for Millennium, except for the portion within Mt. Vernon. FERC asked the parties to work to find an acceptable alternate route within Mt. Vernon. In May 2002, an agreement on an alternative route within Mt. Vernon was reached between Millennium, Mt. Vernon, and Con Edison. Sponsors of the Canadian portion of the project recently withdrew their applications filed at the Canadian National Energy Board (NEB). They attribute this action to delays in receiving U.S. regulatory approvals for Millennium and pledge continuing support to the project and say that they intend to re-apply for NEB approval at an appropriate time. At this point, the proposed November 2002 in-service date is no longer feasible.

Islander East Project.³² One of three projects proposed to connect existing interstate pipelines to basically the same point on eastern Long Island. Islander East would consist of approximately 45 miles of new 24-inch diameter pipe from a point near Cheshire, CT, where it will interconnect with the existing AGT mainline, across the Long Island Sound to the town of Brookhaven, NY. Islander East will have an initial capacity of 285 MDT/D, with a proposed in-service date of November 2003. FERC issued a favorable Draft Environmental Impact Statement (DEIS) to Islander East in March 2002.

Connecticut-Long Island Lateral Project. Would consist of approximately 50 miles of new pipeline connecting the existing Tennessee pipeline near Agawam, MA, to

³¹ Millennium is sponsored by Columbia Gas, TransCanada, Westcoast and MCN Energy Group.

³² The Islander East Project is sponsored by Duke Energy (50%) and KeySpan (50%).

Long Island.³³ This project has been announced but not yet filed at FERC. The proposed in-service date is November 2003 and the proposed capacity is 450 MDT/D.

Iroquois' Eastern Long Island Expansion Project. Would consist of approximately 20 miles of submarine pipe under Long Island Sound from Iroquois' existing mainline in Milford, CT, to Shoreham, Long Island. The proposed capacity is 175 MMCFD and the proposed in-service date is November 2004. The project was filed at FERC in December 2001.

Texas Eastern Incremental Market Expansion. The TIME project would expand the capacity of the TETCO system by 100 MDT/D (through compression and looping) for delivery to New Jersey Natural Gas Company. The project has been filed at FERC with an expected in-service date of November 2002.

Maritimes & Northeast Expansion. Maritimes & Northeast Pipeline have filed an application with FERC to nearly double the capacity of the existing Maritimes' pipeline from 415 MDT/D to 800 MDT/D, for service in the 2003-04 time frame.

Iroquois Athens. This project is comprised of a second compressor unit (10,000 hp) that would be located at Iroquois' existing compressor station at Athens, New York. The added compression would provide 70 MDT/D of capacity for the Athens Generating Company. Iroquois filed this project at FERC in November 2001, with a proposed in-service date of September 2003.

Iroquois Brookfield. This project is comprised of a new 10,000 hp, compressor station to be located adjacent to Iroquois' existing Brookfield, CT meter station. The added compression would provide 25 MDT/D of capacity for PP&L Energy Plus LLC (a marketing company) and up to 60 MDT/D for Astoria Energy Company. Iroquois filed this project with FERC in November 2001, with a proposed in-service date of November 2003.

ConneXion Project. Tennessee's ConneXion project involves expanding storage capacity in Pennsylvania and expanding its delivery capacity from those storage areas to New York City by about 500 MDT/D. Tennessee plans to file an application at FERC in the fall/winter of 2002 and expects the facilities to be in-service by November 2004.

Northwinds Pipeline. Would be a new 215 mile, 30-inch pipeline extending from Kirkwell, Ontario, cross the U.S. near Buffalo, NY and follow a southerly route to the

³³ The sponsor of this project is Tennessee.

Ellisburg-Leidy storage area in Pennsylvania.³⁴ It would have an initial capacity of 500 MDT/D and provide shippers access to the Dawn, Ontario hub and storage facilities. Northwinds plans to file for regulatory approvals in the spring of 2002, with a target in-service date of late 2004.

Blue Atlantic Project. El Paso Corporation has announced plans for a new approximately 750 mile, 36-inch pipeline from offshore Nova Scotia to Long Island. It would have an initial capacity of 1000 MDT/D and is estimated to cost between \$1.6 billion and \$1.8 billion. El Paso anticipates filing for approvals in late 2002, with a targeted in-service date of late 2005.

The development of gas resources located in the Scotian Shelf represents a significant new supply source to the Northeast. While several estimates of the potential gas supplies in the Scotian Shelf are in the 18 TCF range, some estimates are 50 TCF or even higher. Production from this area was 121 BCF in 2000, but is expected to increase to between 400 and 800 BCF by 2010³⁵. These gas supplies are not only located closer to the Northeast market than traditional Gulf Coast or Canadian supplies but are a new supply source that will increase the diversity of gas supplies to the Northeast.

LDC Distribution System Capacity

Distribution system improvements will be needed to serve the power generation market as well as expanded core markets. Since several of the proposed power generation projects would be located in and around the Con Edison gas service territory, the company has an ongoing effort to work with project sponsors to identify their needs and to determine what distribution system improvements will be needed.

Further, the LDC system infrastructure is aging and, to ensure safe operations, there is a need to continue priority replacement programs on portions of the distribution system as well as to verify LDC transmission system integrity. The LDCs and Department of Public Service staff have been engaged in a collaborative effort to address the integrity of transmission systems. That effort involves the development of a risk assessment model to calculate and prioritize the relative risk of transmission pipeline segments and to work to reduce the highest risks to the pipelines. Both LDCs and operators of interstate pipelines, which deliver gas to the State, will need to verify transmission line integrity. Coordination of integrity verification efforts by both LDCs and interstate pipelines will be needed to prevent adverse impacts on continuous gas

³⁴ The sponsors are TransCanada Pipelines and National Fuel Gas Company

³⁵ Canadian Natural Gas, Market Review & Outlook, May 2001, Natural Resources Canada

deliveries. The federal Department of Transportation has issued a proposed definition of “high consequence areas” and is expected to issue a notice of proposed rulemaking specifying gas pipeline operator requirements for high consequence areas in the spring of 2002. There is a need for continued research and development (R&D) activities to develop new methods of verifying transmission system integrity as well as to develop cost-effective techniques to maintain and upgrade the existing distribution system.

Infrastructure Security

Interstate pipelines are periodically patrolled by helicopter, and routinely inspected and maintained. Major gas facilities, such as gas processing plants, LNG plants, and compressor stations are fenced and typically guarded. The security of gas delivery facilities has not been a problem historically. However, in light of the September 11, 2001 terrorist attacks, Governor Pataki created the Office of Public Security to assess the vulnerability of critical infrastructures to terrorist attack and to develop a comprehensive Statewide anti-terrorism strategy. Concurrently, the Department of Public Service has established the Security Assessment Team to assess utility efforts to maintain system reliability and security.

Analysis of Infrastructure Issues

It is clear that additional capacity will be needed to meet anticipated increases in natural gas demand in the State. However, because of uncertainties regarding the timing of new merchant power plants and their impact on the operation of existing gas-fired generators, the extent and timing of that need are less clear. The NYSERDA-NYISO study, discussed below, evaluated the adequacy natural gas pipeline capacity to meet the needs of the electricity generation market.

FUTURE NATURAL GAS DEMAND, SUPPLY, AND PRICE

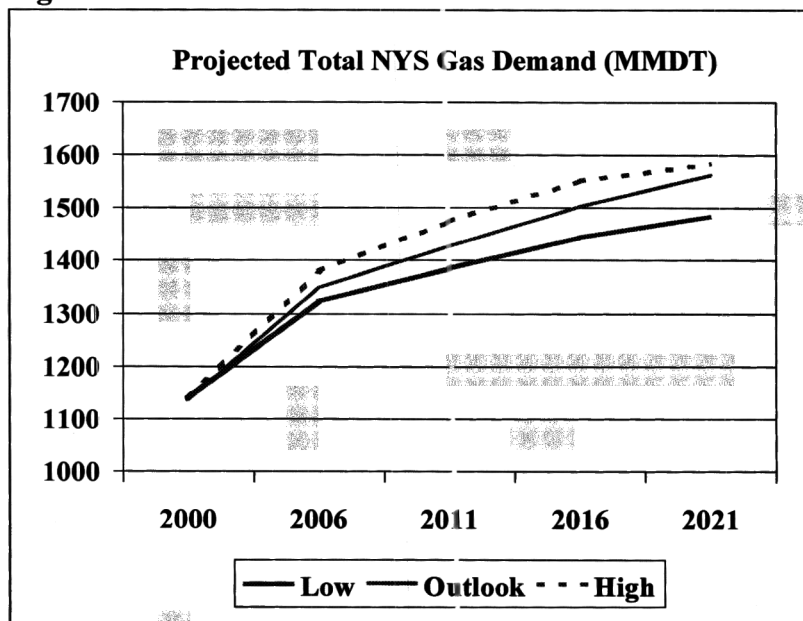
Approach

Future natural gas demand, supply, and price are especially difficult to project due to the dynamic changes taking place in the gas and electric industries and rapidly changing market conditions. These forecasts were developed from the *2002 Annual Energy Outlook* projections prepared by the federal Energy Information Administration (EIA). Considering the market uncertainties, a range of possibilities was examined.

Natural Gas Demand

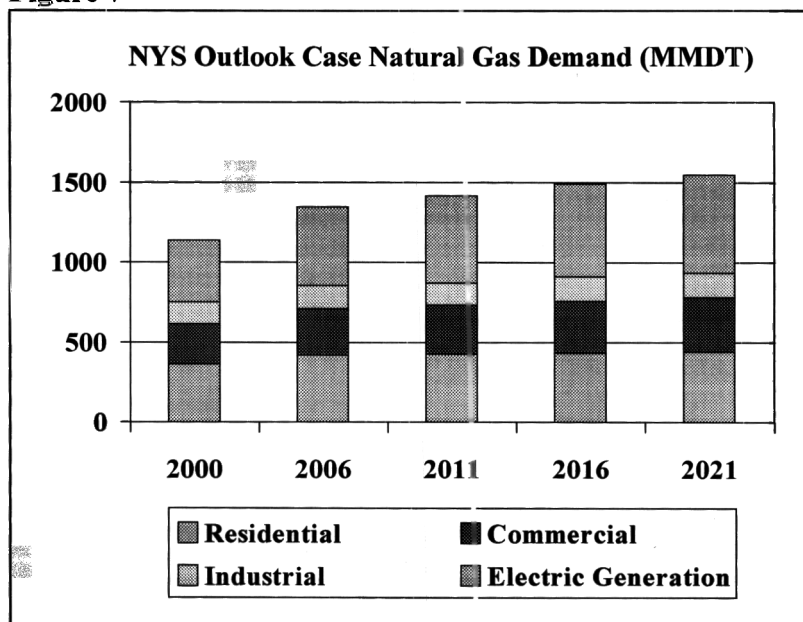
On a Statewide basis, the projected range of overall demand growth is expected to be 1.3% per year in the low case, to 1.6% per year in the high case, with the Outlook Case at 1.5% per year, as shown in Figure 6. Figure 7 shows the breakdown by sector of the Outlook Case demand projection.

Figure 6



On a Statewide basis, the projected range of core market demand growth is expected to be 0.9% year in the low case to 1.25% per year in the High Case, with the Outlook Case at 1.1% per year, as shown in Figure 8.³⁶

Figure 7



The largest increase in gas use in New York is expected to be for power generation. However, this expectation is subject to the greatest uncertainty because there is no way of knowing precisely how many new power plants will be built, how and when they will operate, and

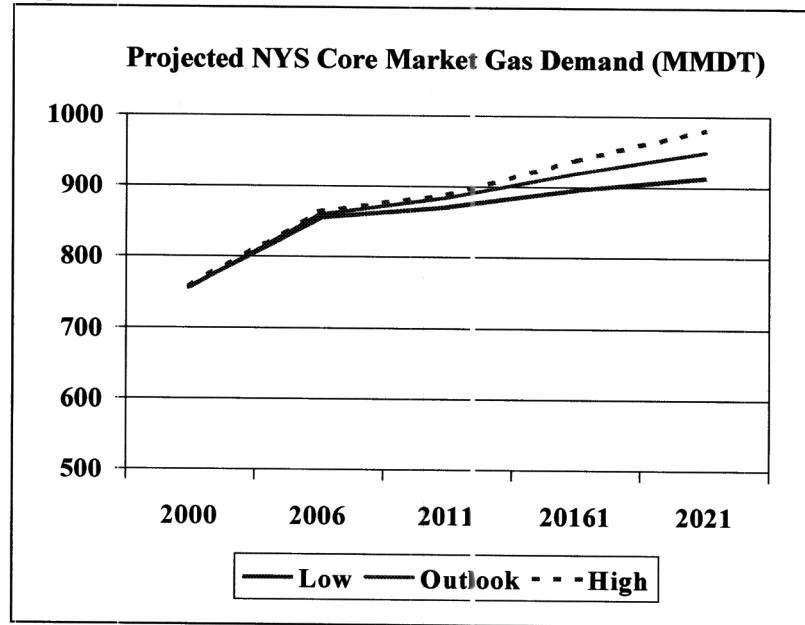
³⁶ It should be noted that these forecasts are for annual requirements and peak-day requirements (which determine capacity requirements) are expected to increase at a faster rate.

how their operation will impact the operation of existing generation stations.

NYSERDA and the New York Independent System Operator (NYISO) initiated a study of the inter-relationships between the electricity and natural gas systems in New York. Through integrated modeling of the natural gas pipeline and electric generation

systems, the study analyzed the level of gas and oil use for electric generation under a variety of pipeline and electric generation expansion scenarios¹⁷. Ongoing analysis is examining the interactions of the gas and electric system in contingency situations.

Figure 8



As a starting point, for the year 2002, the analysis assumes that electric generation and natural gas system expansion projects currently under construction, or expected to be in service through 2003, are completed.³⁸ This includes a net increase in electric generating capacity of 527 MW³⁹ and an increase in natural gas pipeline capacity of 465 MDT/D⁴⁰. Most of this gas pipeline capacity increase (395 MDT/D) is to the downstate market. This represents approximately a 12% increase in pipeline capacity to the

³⁷ In this analysis, the current and projected needs of the core market (residential, commercial and industrial customers) are considered and are met first.

³⁸ It should be noted that recommendations for reducing State greenhouse gas emissions, discussed in Section 2.3, were developed following the completion of the analysis contained in this study. Such recommendations could further increase the demand for natural gas to generate electricity.

³⁹ NYPA and LIPA additions, and various unit up-ratings.

⁴⁰ Transco MarketLink (115 MDT/D), Iroquois Athens (70 MDT/D), Iroquois Eastchester (230 MDT/D), and another 50 MDT/D from among the following projects: Leidy East, Texas Eastern Hanover Compressor, and Stagecoach (see section on Infrastructure Issues in the Natural Gas Assessment for a description of these projects).

downstate market since November 2001. About 30% of the 395 MDT/D increase in pipeline capacity to the downstate area has been constructed to date.

Projected changes in the maximum annual amount of natural gas that can be delivered and burned (and the corresponding, or minimum oil use) in power plants between 2002 and 2005 are shown in Table 1⁴¹.

TABLE 1

Changes (from 2002) in Annual Maximum Gas and Corresponding Oil Consumption for Electricity Generation (MMDT)											
Generation Capacity Added*	Year	Amount of Post 2003 Pipeline Capacity Added (MDT per day)									
		0		300		400		500		800	
		Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil
1030 MW ⁴²	2005	25	6	41	-10						
1780 MW ⁴³	2005	15	4	34	-10	36	-12				
4435 MW ⁴⁴	2005	-14	0	31	-7	38	-12	41	-14	44	-18
5015 MW ⁴⁵	2010	64	77	116	4	123	-6	127	-12	135	-18

*While the scenarios are based on actual new generation proposals, they should be taken as representative cases given the current uncertainties regarding which projects will actually be built.

These changes are relatively small because the increased use of gas in new combined cycle units and gas turbine units is nearly offset by a decline in gas used in (existing) steam units⁴⁶. This is because the heat rates of new combined cycle units are about 7,000 Btu/Kwh, as opposed to 10,000-12,000 Btu/Kwh for existing steam units, so

⁴¹ To test the ability of the gas delivery system to meet maximum electricity generation gas requirements, the price inputs to the model were set so that gas would be the economic fuel of choice. Therefore, the results shown in this table represent changes in the maximum amount of gas (and corresponding minimum amount of oil) that the electric system would require, constrained only by the availability of natural gas pipeline capacity.

⁴² Includes capacity additions from the Athens and East River projects.

⁴³ Includes capacity additions in the 1030 MW case, plus the Ravenswood and Poletti projects.

⁴⁴ Includes capacity additions in the 1780 MW case, plus the Orion, Heritage, Albany, and Astoria projects.

⁴⁵ This includes capacity additions in the 4435 MW case, plus the Brookhaven project.

⁴⁶ For reference, the 2002 values are 453 MMDT for gas and 18 MDT for oil.

that about 50 percent more power can be generated with the same amount of gas. As can be seen, for a given level of pipeline capacity, as more new generation is added, the change in maximum natural gas use decreases and oil use generally decreases. Again, this is the result of new, efficient combined-cycle generation units displacing gas from existing, steam electric units. For a given level of new generation capacity, as more natural gas pipeline capacity is added, the maximum gas use increases and oil use decreases. This is because removing natural gas pipeline capacity constraints allows more gas to be delivered to electric generation units. By 2010, the increase in gas use becomes more significant as more generation is required to meet additional electricity demand.⁴⁷

The study focused on an analysis of the downstate area where much of the proposed increase in electric generation capacity would be located, and the ability of various increases in gas pipeline capacity to meet downstate electricity generation needs.⁴⁸ As discussed earlier, several pipeline projects for the downstate area have been proposed that collectively could increase capacity by about 800 MDT/D. The study did not evaluate particular pipeline projects, but instead examined post-2003 capacity addition levels of 0, 300, 400, 500 and 800 MDT/D.

Table 2 shows the percentage of electric generation requirements that would be met by gas under these scenarios in 2005.

TABLE 2

Percentage of Annual Electric Generation Requirements that Could be Met by Gas - Downstate Area 2005					
Amount of Electric Generation Capacity Added	Amount of New Pipeline Capacity Added Post-2003 (MDT per day)				
	0	300	400	500	800
1030 MW	93	98			
1780 MW	91	98	98		
4435 MW	79	95	98	99	100

As can be seen, the addition of 300 MDT per day of new, post-2003 capacity will meet at least 95% of electric generation fuel requirements. Oil would be used to provide the remaining fuel, at levels that are predicted to be below historical oil use levels. If the

⁴⁷ The study assumes that electricity demand will increase at a rate of about 1%/year between 2002 and 2005 and about 0.9%/year between 2005 and 2010.

⁴⁸ The study did not model LDC systems.

amount of new pipeline capacity is increased to 800 MDT/D, all of the electric generation requirements (including the highest generation capacity addition case) can be fully met using natural gas. By 2010, an additional 100-200 MDT/D of pipeline capacity would be needed to maintain oil use at the high generation capacity addition case levels in 2005.

The study's overall findings are that:

- If no post-2003 pipeline expansion projects are built, the existing gas and oil systems will be adequate to meet all generation scenarios.
- Pipeline capacity additions of between 300 MDT per day and 800 MDT per day would provide additional benefits to the electricity and natural gas systems, including enabling the use of larger quantities of cleaner-burning natural gas and providing better contingency protections.⁴⁹ Nonetheless, the more natural gas pipeline capacity built and used to serve electricity generation, the more dependent the electricity system is on natural gas availability and the more exposed it is to natural gas price variation.
- If 800 MDT per day of post-2003 pipeline capacity are built into the downstate New York area, gas could meet 100% of all generation scenario fuel needs.
- If fewer pipeline expansions and/or less additional generating capacity are added, a substantial portion of the maximum potential gas demand for generation can be met. Some oil would need to be burned, but the total annual oil burn in all cases in 2005 would be less than the amount burned in 2000 and 2001.

These findings assume that the steam units remain available, and can use residual oil when needed, providing important flexibility to meet peak electric generation needs. The addition of 4,435 MW of generation capacity and 300 MDT/D of pipeline capacity will result in existing steam units running at very low load factors with low earnings. Unless these plants can offset this loss of earnings from the capacity and ancillary services markets they could become uneconomic and retire. To the extent that these steam units are retired, either more pipeline capacity will be needed to meet the electric generation needs, or new combined cycle plants will need to have the ability to burn oil for longer periods. These new combined cycle plants, as currently planned, will have neither the oil storage capacity nor air emissions permits to do that. The residual oil storage tanks at existing steam-units are a valuable asset that could be converted to distillate oil storage. However, the inability to burn distillate oil in new, efficient combined cycle plants for more than 30 days would result in the need to burn greater quantities of more polluting residual oil in remaining existing inefficient steam electric

⁴⁹ Work is continuing to assess the impact on the electricity and natural gas systems resulting from additional contingencies.

units. These issues highlight the importance of the ability to use oil as a substitute for gas pipeline capacity to generation system reliability.

The study considers pipeline capacity that is built to the New York market as capacity that will remain available to customers in New York. This assumes an open pipeline capacity market where bidders can acquire capacity on a short-term basis if they are willing to bid high enough. However, this same pipeline capacity could be used to deliver gas to upstream points or even downstream points (*e.g.*, New England). There is a risk that these customers (*e.g.*, new generators or other users) might emerge and be willing to sign a long-term contract for that pipeline capacity. If that were to happen, that pipeline capacity would become unavailable to the New York market, and building replacement pipeline capacity may take several years.

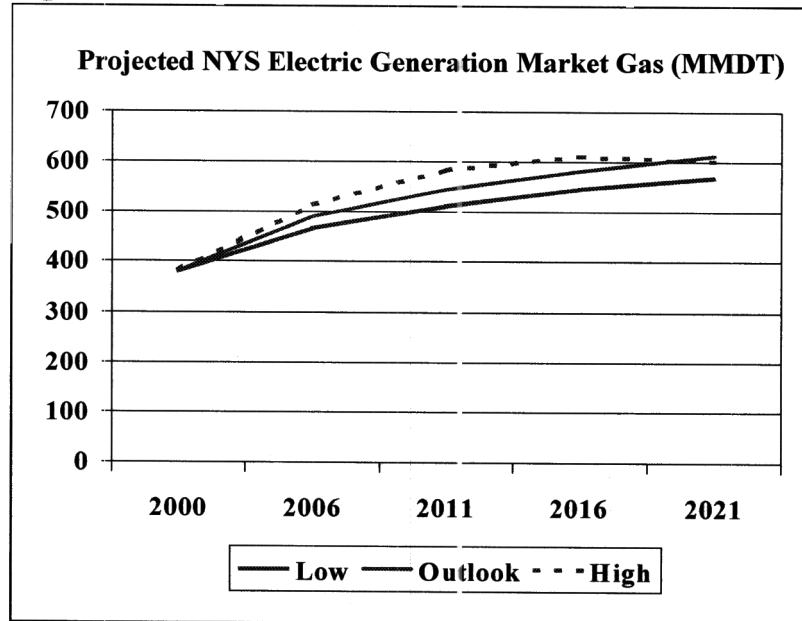
The study also assumes normal winter weather for the purpose of calculating non-generation loads. LDC's hold capacity to meet severe weather requirements⁵⁰ and can offer excess capacity to the market when the weather is less than severe. To the extent that winter weather is colder than normal, less pipeline capacity will be available for generation. If New

York State had a severe winter, about 100 MDT per day of additional pipeline capacity would be needed to keep oil use at "normal winter" levels in 2005.

In this plan, over the long-term on a Statewide basis, the projected range of power generation demand growth is expected to be 1.9% per year in the Low Case, to 2.2% per year

in the High Case, with the Outlook Case at 2.3% per year, as shown in Figure 9.

Figure 9



⁵⁰ The definition of a "severe winter" varies by LDC, but downstate it is about 13% colder than normal.

Natural Gas Price

It is especially difficult to project future natural gas prices due to uncertainties and rapid changes in natural gas markets. Early in the year 2000, no industry analysts predicted that gas prices would reach anywhere near \$10/DT during the 2000-2001 winter. Similarly, no one predicted that gas prices would fall below \$2.50/DT

before the 2001-02 winter. Further, long-term price projections are not intended to, and do not reflect, short-term price variations observed in the market. However, such price volatility will likely be a permanent feature of the competitive gas market.

EIA projections show Outlook Case natural gas wellhead prices trending down and then gradually increasing, but not reaching, the level of 2000 prices in real terms over the planning period (see Figure 10). Retail core market prices are expected to decrease slightly in real

terms over the forecast period. This is because, in addition to anticipated decreases in commodity cost, there are also anticipated reductions in transmission and distribution system costs. Figures 11, 12, and 13 show the range of core market prices for the

Figure 10

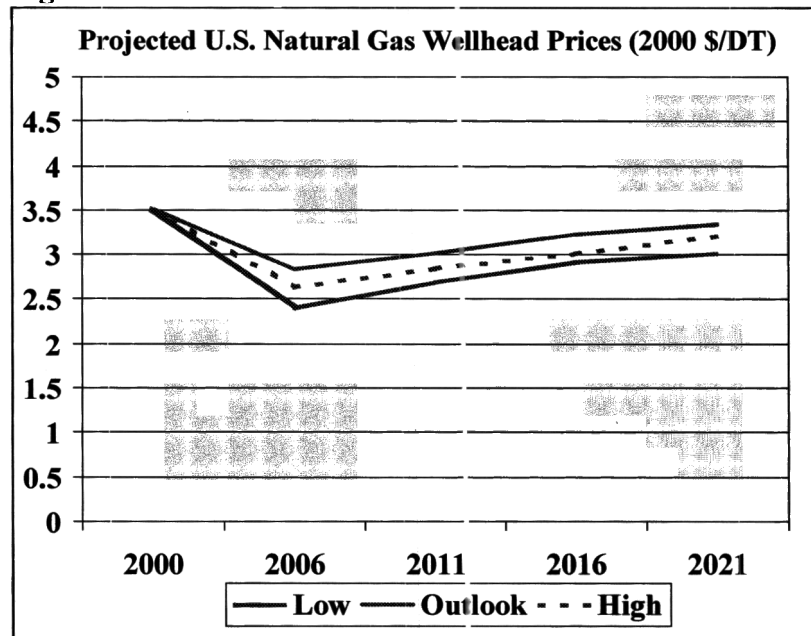
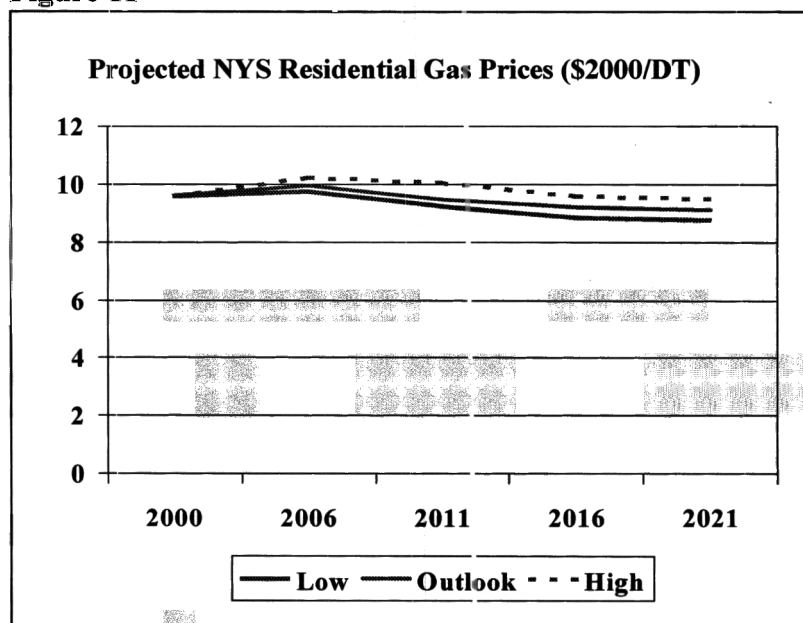


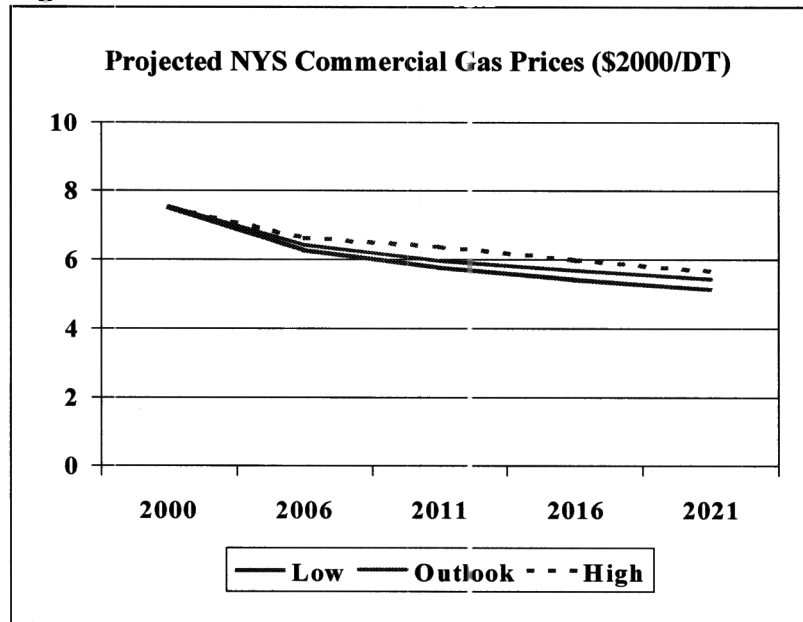
Figure 11



residential, commercial, and industrial sectors, respectively.

Retail prices of gas for power generation are also expected to decrease slightly and then increase slightly, essentially remaining flat over the forecast period. Figure 14 shows the range of gas prices for the power generation sector.

Figure 12



Natural Gas Supplies

According to EIA's projections, there will be adequate supplies of natural gas at all forecast levels of demand and price. The largest increase in supply will come from domestic sources, along with increased dependence on Canadian gas and LNG imports. New York State gas production will likely increase significantly.

However, since demand is expected to grow significantly, the portion of the State's needs met with indigenous gas is not likely to change much.

Figure 13

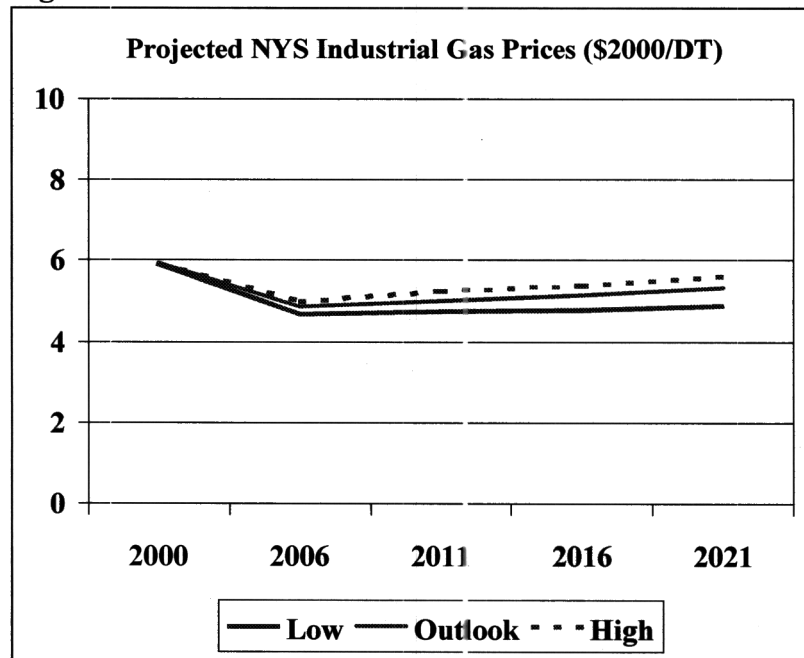
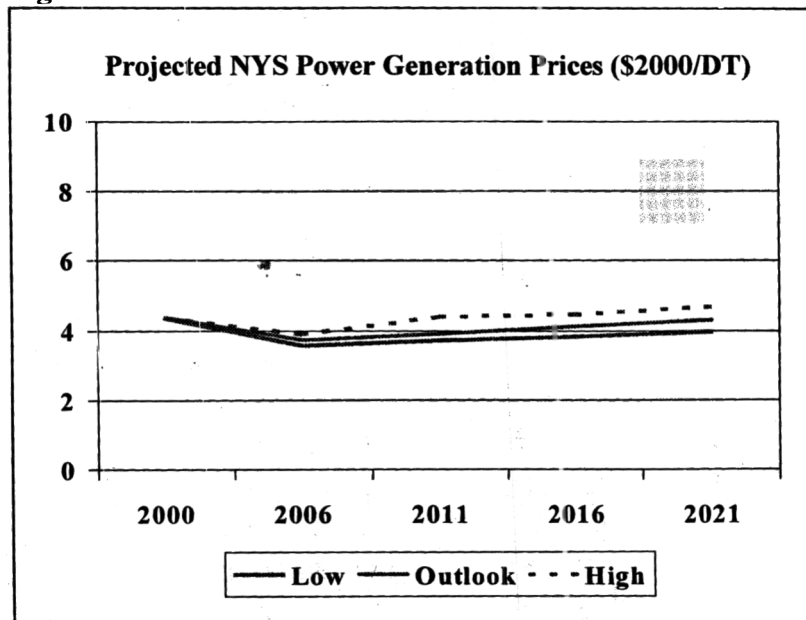


Figure 14



FINDINGS AND CONCLUSIONS

The demand for natural gas is expected to expand significantly over the planning period, particularly in the near-term, with the greatest increase in the use of gas for power generation.

More pipeline capacity will be needed to meet the increased demand for natural gas. Interest in expanding interstate pipeline delivery capacity to the Northeast and New York State continues to be strong. The local distribution company (LDC) systems will also have to be expanded to meet these increased needs.

The Federal Energy Regulatory Commission (FERC) recently approved 9 natural gas pipeline projects to serve the Northeast, and another 11 projects have been proposed.

Natural gas prices will decrease slightly in real dollars over the long-term and are expected to remain volatile.

There is a general need to continue LDC system integrity and safety programs, as well as to continue research and development efforts to develop cost savings techniques to maintain and upgrade the existing distribution system.